9.2 Energy Alternatives

This section evaluates the two energy options to satisfy future baseline electrical demand—those that do not require new generation capacity (Subsection 9.2.1), and those that do (Subsection 9.2.2). The regulatory basis for this discussion is found in 10 CFR 51.45(b)(3), as adopted by reference 10 CFR 51.50(c).

Some of the new generation alternatives identified in Subsection 9.2.2 may be readily eliminated from the evaluation. Those not eliminated are further evaluated in Subsection 9.2.3 with emphasis on environmental impacts, reliability, and economic factors.

Throughout this discussion, it is important to note that the additional STP units would be constructed and operated to serve as an independent merchant baseload power producer (also referred to as a “merchant plant” or “merchant generator”). The power produced would be sold on the open wholesale market, without specific consideration to a traditional service area or reserve margin objectives. For the purposes of this alternatives analysis, the “region of interest” has been defined as service territory served by the Energy Reliability Council of Texas (ERCOT) rather than the more traditional “relevant service area.” The delineation of this region of interest is consistent with current deregulation policies and the proposed location of the facility within the territory served by ERCOT. The major functions of ERCOT are described in a paper available from the ERCOT website titled "ERCOT Protocols Section 1 – Overview," (Reference 9.2-1) and are also discussed in Chapter 8 of this Environmental Report.

9.2.1 Alternatives That Do Not Require New Generation Capacity

This section is intended to provide an assessment of the economic and technical feasibility to meet the demand for energy without construction of new generation capacity. Potential options are to:

- Purchase power from other utilities or power generators
- Reactivate or extend the service life of existing plants within the power system
- Implement Demand Side Management actions (including conservation measures)
- Use an existing peaking facility to provide baseload power
- Combine these elements that would be equivalent to the output of the project and, therefore, eliminate its need

9.2.1.1 Purchase Power from Other Utilities or Power Generators

In a traditional alternatives analysis for examining the energy alternative to utility generation capacity, the purchased power alternative meant that the utility would meet a portion of its service territory demand using power that it purchased from another utility. Deregulation, however, has changed the traditional analysis. In the current deregulated ERCOT market, one of the joint owners of the proposed project, NRG Energy, is a power generation company that operates as an independent provider of wholesale electricity. As a power generation company, NRG Energy would not be able to offer competitively priced power if it had to purchase electricity for resale in the wholesale market.

The other joint owner of the proposed project, CPS Energy, continues to operate as a traditional utility. As a traditional utility, one of CPS Energy's goals is to provide the lowest cost-reliable power supply to its customers. In some instances, when the price is right, CPS Energy makes short-term purchases of power on the wholesale market for the benefit of customers. However, to maintain an adequate reserve of generating capacity for reliability and wholesale market risk reduction, CPS Energy has determined that the proposed nuclear project is the lowest cost option. CPS Energy has and continues to evaluate power markets for opportunities to supplement its generation portfolio. However, power supply agreements are too costly to be a viable alternative to the proposed nuclear project.

Finally, as discussed in Chapter 8, the region of interest for the need for power analysis is ERCOT. Chapter 8 demonstrates that within ERCOT there is a need for power from STP 3 & 4 plus other new generating facilities. Chapter 8 also demonstrates that there are very limited interconnections between ERCOT and outside areas. Given the limited interconnections, it would not be possible to supply the need for power within ERCOT with power purchased from outside of ERCOT.

9.2.1.2 Reactivate or Extend Service Life of Existing Plants

Reactivating or extending the service life of existing plants could reduce the need for a new nuclear power station. STPNOC has no plans to retire either of the existing STP units. Fossil plants that have been retired or that are slated for retirement tend to be ones that are old enough to have difficulty in meeting current restrictions on air contaminant emissions. In the face of increasingly stringent restrictions, delaying retirement, or reactivating plants to avoid development of large baseloaded plant would be unreasonable. To meet regulatory requirements, major construction to retrofit emission control devices, upgrade, or replace plant components would likely be required. STPNOC concluded that the environmental impacts of such a scenario are bounded by the coal- and gas-fired alternatives. Consequently, reactivation or extended service life for existing plants are not considered reasonable or environmentally preferable alternative energy sources for the owners of the proposed project.

9.2.1.3 Demand Side Management

Historically, state regulatory bodies have required regulated utilities to institute programs designed to reduce demand for electricity; however, the capacity of the proposed baseload unit could not reasonably be replaced with conservation. Demand Side Management programs included energy conservation and load modification measures. In the current deregulated ERCOT market, NRG Energy anticipates it would not be able to offer competitively priced power if it had to retain an extensive conservation and load modification incentive program.

As discussed in Subsection 8.4.1, ERCOT does have a Demand Side Working Group to promote demand side management. ERCOT's determination of the need for power accounts for efforts to reduce demand. Therefore, even factoring in demand side management, there will be a need for power in ERCOT at the time STP 3 & 4 is scheduled to begin operation, and demand side management is not a reasonable alternative to new generating facilities.

Finally, the purpose of STP 3 & 4 is to generate baseload power, and NRG's purpose for the project is to sell baseload power on the wholesale market. Demand side management does not generate baseload power, and therefore does not serve the purpose of the project. Therefore, demand side management is not a reasonable alternative.

9.2.1.4 Use an Existing Peaking Facility to Provide Baseload Power

Baseload facilities are normally used to satisfy all or part of the minimum or baseload of the system and, as a consequence, operate at full power continuously throughout the year. Peaking facilities usually run for short periods when demand on the grid exceeds baseload generation capacity in the region. Continuously running a peaking facility to provide baseload power could reduce the need for a new nuclear power station. Peaking facilities are small facilities, generally fueled by oil or natural gas, that quickly can be turned on and off according to swings in demand. Because they have a relatively low installed capital cost, simple cycle combustion turbines and diesel generators are the most prevalent peaking technologies. Peaking technologies are generally less fuel-efficient than baseload technologies using similar fuels. Consequently, peaking technologies are more expensive to operate and their impact on the environment per unit of generation is greater than the impact from baseload technologies using similar fuels. Therefore, using existing peaking facilities to provide baseload power is not considered a reasonable and/or environmentally preferable alternative energy source for the owners of the proposed project.

9.2.2 Alternatives That Require New Generation Capacity

9.2.2.1 Introduction

This section discusses potential alternatives that require new generation capacity and could reasonably be expected to meet the additional generation capacity expected from the proposed project at the STP site. The STPNOC COL application is premised on the construction and operation of a facility that would serve as a large baseload generator. Any feasible alternative would also need to be able to provide baseload power. For this evaluation, STPNOC determined that NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants" (Reference 9.2-2), identifies a useful set of alternative technologies. To generate the reasonable set of alternatives in NUREG-1437, NRC included commonly known generation technologies and consulted various state energy plans to identify alternative generation sources that are typically considered by state authorities across the country. From this review, NRC established a reasonable set of alternative technologies for power generation. This section considers those same alternatives.

Over the lifetime of the proposed project, technology is expected to continue to improve operational and environmental performances. Thus, any analyses of future relative competitiveness or impacts are subject to these uncertainties. However, in the case of alternatives evaluated in Subsection 9.2.2, STPNOC believes that sufficient knowledge is available to make a reasonable assessment.

Energy alternatives identified for consideration in NUREG-1437 include coal, natural gas, petroleum fuels, wind, geothermal, hydroelectric, wood waste, and municipal solid waste, energy crops, and solar. Although NUREG-1437 is specific to license renewal, the alternatives analysis therein is generic and independent of license renewal and can be compared to the proposed action to determine if the alternative technology represents a reasonable alternative and satisfies the intent and requirements of the proposed action.

The alternative technologies considered in this analysis are consistent with national policy goals for energy use and are not prohibited by federal, state, or local regulations. Each of the alternatives are assessed and discussed in the subsequent sections relative to the following criteria:

- The alternative energy conversion technology is developed, proven, and available in the region of interest at the start of commercial operation of the proposed project.
- The alternative energy source provides baseload generation capacity equivalent to the level in the proposed action (i.e., STP 3 & 4).
- The alternative energy source does not result in environmental impacts in excess of a nuclear plant.
- The costs of an alternative energy source do not exceed the costs that make it economically impractical.

Several of the alternative energy sources were considered technically or economically infeasible after a preliminary review and were not considered further. Alternatives that were considered to be technically and economically feasible are assessed in further detail in Subsection 9.2.3.

STPNOC proposed a two-unit plant for the STP site based on General Electric’s Advanced Boiling Water Reactor (ABWR) configuration. For the purpose of analysis, STPNOC assumed a target value of 2700 MWe for the net electrical output from the proposed STP units. This is considered a reasonable value and is the basis for the alternatives analysis in the following subsections.

9.2.2.2 Wind

As of December 2006, 2508 MWe of wind generation has been in service in the ERCOT region (Reference 9.2-3). Wind power systems produce power intermittently because they are only operational when the wind blows at sufficient velocity and duration. Although recent advances in technology have improved wind turbine reliability, the capacity factors for wind power systems generally range from 25% to 40% (Reference 9.2-4) and the National Regulatory Research Institute reports an average capacity factor of around 30% (Reference 9.2-5).

The energy potential in the wind is expressed by wind generation classes that range from 1 (least energetic) to 7 (most energetic). In a Class 1 region, for a wind measurement height of 164 feet, the average wind speed is less than 12.5 mph and offers a wind power of less than 200 watts per square meter. A Class 7 region has an average of more than 19.7 mph and offers a wind power of more than 800 watts per square meter. These speed ranges are based on wind speeds measured at 164 feet above ground surface (Reference 9.2-6). Wind regimes of Class 4 or higher are potentially economical for the advanced utility-scale wind turbine technology currently under development. Class 3 wind regimes may be potentially economical for future utility-scale technology (Reference 9.2-7).

Within the ERCOT region, mountainous parts of west Texas, and perhaps even the lower Gulf Coast, contain areas with winds presently suitable for electric power generation from wind energy (Reference 9.2-8). Wind resource studies indicate that within the United States, the potential wind resources in Texas are second only to those in North Dakota (Reference 9.2-9). AWS Truewind submitted a Wind Generation Assessment to ERCOT in January 2007 that identifies 25 viable Competitive Renewable Energy Zones distributed across the state with an estimated 1200 potential wind project sites. The estimated wind energy potential exceeds 130,000 MWe in a typical historic year. Most of these are located in the north, west, and central areas of the ERCOT region, although viable areas are also present near the coast southwest of Galveston (Reference 9.2-10). However, STPNOC would have to acquire land rights to build wind generation facilities in the more favorable regions within ERCOT.

In open, flat terrain, a utility-scale wind plant requires about 60 acres per megawatt of installed capacity. However, 5% (3 acres) or less of this area is actually occupied by turbines, access roads, and other equipment. The other 95% can be used for compatible activities such as farming or ranching (Reference 9.2-11). Based on this data, to generate a net output of 2700 MWe, a wind farm that operates with 30% capacity factor (an average value) would require as much as 540,000 acres (844 square miles), with about 27,000 acres (42 square miles) occupied by turbines and support facilities (Reference 9.2-11). Based on the amount of land needed, the wind alternative would require a large greenfield site, which would result in a large environmental impact.

Wind resources off the coast of Texas also offer potential for wind-based energy production (Reference 9.2-12). Offshore wind turbines have several advantages over onshore turbines. At a sufficient distance from the coast, visual intrusion is minimized and wind turbines can be larger, which increases the overall installed capacity per unit area. In addition, studies have shown that very high tip-speed designs and reduced blade chord can reduce loads throughout a wind turbine structure and reduce costs; however, these designs have been restricted on land because of increased aero-acoustics noise emissions, but offshore installations would not be subject to the same limitations. These improvements can reduce the cost of energy by as much as 15%. Design modifications such as downwind operation and the use of high-tip speed flexible designs could further reduce capital cost. In addition, offshore winds tend to be faster and more uniform than onshore winds. A higher, steadier wind means less wear on the turbine components and more electricity generated per square meter of swept rotor area. Onshore turbines are often located in remote areas, where the electricity must be transmitted by relatively long power lines to densely populated regions, but offshore turbines can be located relatively close to urban load centers which can simplify transmission issues (Reference 9.2-13).

Despite these advantages, however, significant challenges associated with offshore wind power development exist. Environmental conditions at sea are more severe than on land, and the sea poses saltwater corrosion concerns and additional loads from waves. To date, turbine manufacturers have taken conventional land-based turbine designs, upgraded their electrical and corrosion-control systems to facilitate a marine service environment, and placed them on concrete bases or steel monopiles to anchor them to the seabed. Experience with offshore wind power development in Europe indicates that the use of conventional land-based turbine designs in a marine environment leads to reliability issues and increased maintenance costs. New turbine designs would be needed to withstand harsh offshore conditions. In addition, investment costs are higher and accessibility is more difficult, and these factors pose increased capital and maintenance costs (Reference 9.2-13).

Installation of wind power equipment can pose aesthetic concerns, particularly on mountaintops. Scenic vistas are important and considerable public resistance to the use of mountain ridges for the location of wind farms is likely. Public resistance to the use of coastal areas for wind farms is also likely for similar reasons (Reference 9.2-5).

The National Regulatory Research Institute estimates that the current overnight construction cost (in 2006 dollars) for an onshore 50 MW wind facility would range from $1150 to $1200 per kilowatt. A large wind facility could generate power at a cost of between $0.04 and $0.06 per kilowatt-hour (Reference 9.2-5).

Based on this analysis, STPNOC has determined that wind energy is developed, proven, and available in the ERCOT region at the start of commercial operation of the proposed project; however, the capacity factor for wind energy is inadequate to provide baseload power. In addition, wind energy has large land use requirements and the associated construction and ecological impacts. For these reasons, wind power alone is not a feasible alternative for baseload power in the ERCOT region. However, wind power could be included in a combination of alternatives to the proposed project. Combinations of alternatives are discussed in Subsection 9.2.2.12.

9.2.2.3 Solar Technologies

There are two basic types of solar technologies that produce electrical power—photovoltaic cells (PVs), and concentrated solar power (CSP). For concentrated solar technologies to be effective, the average ground-level insolation rate must be a minimum of 6.0 kWh/m2/day (Reference 9.2-14). The ERCOT region receives 3.5 to 7.0 kWh/m2/day. The western portions of the ERCOT region receive considerably more direct solar radiation than the eastern ERCOT regions. Based on solar radiation maps, numerous areas in the western portion of the ERCOT region would meet or exceed the 6.0 kWh/m2/day minimum insolation standard, especially in the far western portion of the ERCOT region (Reference 9.2-15). Environmental advantages shared by both solar technologies are near-zero emissions and an unlimited supply of fuel (sunlight). Environmental disadvantages shared by both solar technologies are sizeable land use requirements, aesthetic intrusion, and potential use of hazardous materials (lead) to store energy. Additional discussion of CSP and PV technologies is provided below.

9.2.2.3.1 Photovoltaic Cells

In PVs, light particles called photons penetrate the solar cell and knock electrons free from a semiconductor material to create an electric current. As long as an adequate amount of light flows into the cell, electrons flow out of the cell. The cell does not consume its electrons and lose power like a battery. Instead, it operates as a converter that turns one kind of energy (sunlight) into another (electrical current). Individual photovoltaic cells are typically combined into modules that hold about 40 cells, and modules are then mounted into photovoltaic arrays. A large number of arrays can be combined to create a power generation plant (Reference 9.2-16).

Land use requirements (and associated construction and ecological impacts) are larger for a PV plant than for a nuclear plant. The land area required depends on the available solar insolation and type of plant, but based on the data from a 2002 report from the National Renewable Energy Laboratory (NREL), the minimum land area required is 3.8 acres per megawatt (Reference 9.2-14). Because of the land area requirements, a large PV facility could pose aesthetic concerns.

The capacity factor for PV technology ranges from 16% to 30% (Reference 9.2-17). For a solar voltaic system with a midrange capacity factor (24%), the estimated land required to provide 2700 MW of net power to the ERCOT grid is nearly 42,750 acres.

The current estimated overnight capital cost for a PV system (in 2006 dollars) is about $4222 per kilowatt (Reference 9.2-5), and current levelized cost is between $0.20 and $0.25 per kilowatt-hour (Reference 9.2-16). In addition, retired PV system components (e.g., batteries) would likely require disposal as hazardous waste.

Based on this analysis, STPNOC has determined that PV technology is developed and proven, and that viable sites with adequate insolation levels are available in the ERCOT region at the start of commercial operation of the proposed project; however, the capacity factor for PV technology is inadequate to provide baseload power. In addition, PV systems have large land use requirements along with the associated environmental impacts. Furthermore, the cost to generate electrical power from PV systems is several times greater than the cost to generate nuclear power. For these reasons, PV systems are not a feasible or reasonable alternative for baseload power in the ERCOT region.

9.2.2.3.2 Concentrated Solar Power

CSP systems include mirrors that concentrate the sunlight on a fluid system to induce motion. The fluid is then routed through a turbine to generate electricity. This is basically the same type of system that is used to generate electricity from combustion of coal, except the thermal energy comes from the sun instead of from coal combustion. For this reason, CSP systems provide easy integration into the transmission grid. Solar thermal systems can also be equipped with a thermal storage tank to store the energy in the heat transfer fluid. This allows a solar thermal plant to provide dispatchable electric power (Reference 9.2-18). Current CSP systems are as large as 200 MW, with capacity factors that range from 30% to 50% (Reference 9.2-5).

The land area required depends on the available solar insolation and type of plant; however, based on a report from the Western Governors Association, the nominal land area required for a CSP system in a favorable solar region is around 5.0 acres per megawatt (Reference 9.2-18). Because of the land area requirements, a large CSP facility could pose aesthetic concerns.

To provide 2700 MWe of net power to the ERCOT grid, a CSP system that operates at a nominal 40% capacity factor (Reference 9.2-5) would require a land area of 33,750 acres.

The overnight capital cost for a CSP system (based on 2006 dollars) ranges from $2745 to $3410 per kilowatt (Reference 9.2-5). In areas with good solar insolation (at least 6.0 kWh/m2/day), the levelized cost of solar power in 2003 was between $0.108 and $0.187 per kilowatt-hour (Reference 9.2-19). Solar energy costs would likely be on the lower end of this range in the western portions of the ERCOT region that receive stronger ground-level radiation levels.

Based on this analysis, STPNOC has determined that CSP technology is developed and proven, and that viable sites with adequate insolation levels are available in the ERCOT region at the start of commercial operation of the proposed project; however, the capacity factor for CSP technology is inadequate to provide baseload power. In addition, CSP systems have large land use requirements along with the associated environmental impacts. Furthermore, the cost to generate electrical power from CSP systems is several times greater than the cost to generate nuclear power. For these reasons, CSP systems are not a feasible alternative for baseload power in the ERCOT region.

9.2.2.3.3 Hydroelectric Power

Hydroelectric power is a fully commercialized technology. The summer capacity for hydropower in Texas in 2005 was about 673 MW, which represented approximately 0.7% of the electric generation capacity in Texas (Reference 9.2-20). About 532 MW of hydropower was generated in the ERCOT region (Reference 9.2-21). A recent DOE study indicates another 328 MW of hydropower is feasible (Reference 9.2-22); however, the available hydropower in the entire state of Texas is well below the 2700 MW capacity of the proposed project.

Land use for a large-scale hydropower facility is estimated to be quite large. NUREG-1437 estimates land use of 1600 square miles per 1000 MWe generated by hydropower (Reference 9.2-2). Based on this estimate, a 2700 MWe hydroplant that operates at a 40% capacity factor (Reference 9.2-23) would require that about 10,800 square miles be flooded. This would pose a large impact on land use.

If a new hydropower were constructed, wildlife habitat would be lost for terrestrial and free-flowing aquatic biota, and additional habitat would be created for some aquatic species. Associated with the loss of land would be some erosion, sedimentation, dust, equipment exhaust, potential loss of cultural artifacts, and aesthetic impacts from land clearing and excavation. Land that once was lived on, farmed, ranched, forested, hunted, or mined would be submerged under water indefinitely. The original land uses would be replaced by electricity generation and recreation, and perhaps, residential and business developments that take advantage of the lake environment. Changes in water temperature, currents, and amount of sedimentation would produce a different aquatic environment above and below the dam. Alterations to terrestrial and aquatic habitats could change the risks to threatened and endangered species (Reference 9.2-2).

In 2005, the overnight capital cost for a new large-scale hydropower facility was estimated between $1700 and $2300 per kilowatt (Reference 9.2-23), and the levelized cost of electricity produced from new hydropower facilities was estimated at around $0.05 per kilowatt-hour (Reference 9.2-24).

Based on this analysis, STPNOC has determined that although hydropower is developed and proven, the potential for future hydropower development in the ERCOT region is inadequate to supply the power of STP 3 & 4. In addition, hydropower has large land use requirements along with the associated environmental impacts. For these reasons, hydropower is not a feasible alternative for baseload power in the ERCOT region.

9.2.2.3.4 Geothermal

Geothermal energy is a proven resource for power generation. Geothermal power plants use naturally heated fluids in underground reservoirs as an energy source for electricity production. There are three types of geothermal energy plants in use today, dry steam, flash steam, and binary-cycle. Dry steam plants use the earth's thermal energy to spin turbines directly. Flash steam plants pump hot high pressure water into low pressure tanks instantly creating steam which is then used to spin turbine blades to generate electricity. In binary-cycle plants, geothermal steam is used to heat a secondary fluid—one that has a much lower boiling point than water—causing it to vaporize. The vapor is then used to drive turbines (Reference 9.2-5).

Geothermal energy systems can be used for baseload power where this type of energy source is available. Flash steam and binary-cycle geothermal energy systems can operate with a 93% capacity factor (Reference 9.2-5). According to the Energy Information Administration (EIA), as of January 2006, there were no geothermal power plants connected to the ERCOT grid (Reference 9.2-25).

Shallow, high-temperature convective geothermal reservoirs have not been discovered in the ERCOT region or the state. However, recent research indicates that it may be feasible to extract geothermal electric power from geopressured reservoirs of hot water and natural gas or hot wastewater from deep oil and gas wells, using a binary system. Over 600,000 oil and gas wells have been drilled in Texas, most of which are located in the ERCOT region. High-temperature fluid (250°F or greater) has been encountered in many of the wells that are 16,000 feet or deeper, with the highest temperatures above 400°F. Texas also has significant geopressured geothermal resources (Reference 9.2-26).

Researchers have estimated that electric power production potential from Texas oil and gas wells range from 400 MW in the near-term to over 2,000 MW once the technology is demonstrated (Reference 9.2-26).

Geothermal power generation facilities require between 1 and 8 acres per MWe (Reference 9.2-27). Based on a 93% capacity factor, a geothermal power plant with a net output of 2700 MWe would require between 2900 acres (4.5 square miles) and 23,200 acres.

The primary impacts of geothermal plant construction and energy production are gaseous emissions, land use, noise, and potential ground subsidence. Subsidence and reservoir depletion may be a concern if withdrawal of geothermal fluids exceeds natural recharge or injection (Reference 9.2-27).

Overnight construction costs for geothermal power plant (in 2006 dollars) ranges from $2200 to $2300 per kilowatt (Reference 9.2-5). The levelized cost of electricity produced from geothermal power plants located in favorable areas is estimated between $0.045 and $0.073 per kilowatt-hour (Reference 9.2-28).

Based on this analysis, STPNOC has determined that although geothermal power is developed and proven; however, because there are no known shallow high-temperature geothermal sources in the ERCOT region, the potential for future geothermal power currently available technology is inadequate to supply the power of STP 3 & 4. The generation of electricity from geopressured reservoirs or hot wastewater from deep oil and gas wells is in the early stages of development, and STPNOC believes that this technology has not matured sufficiently to support production for a baseload facility. For these reasons, geothermal power is not a feasible alternative for baseload power in the ERCOT region.

9.2.2.3.5 Biomass Related Fuels

Biopower refers to electric power generated from converted vegetation (i.e., biomass). The most common biomass resources today are waste wood and agricultural crop residues such as corn and sugar cane. Research is underway to explore the production of switchgrass and other crops for the specific purpose of biomass conversion for electricity production (Reference 9.2-5).

Biopower generation is a two-step process. The first step is to convert biomass feed stock into what is known as biofuel. The second step is to convert biofuel into electricity via combustion. Most biopower today is produced in direct combustion gas turbines, but it can also be used in combined-cycle turbines, diesel engines, or serve as a substitute in existing coal-fired burners (Reference 9.2-5). Power from biomass is a proven commercial electricity generation option in the United States (Reference 9.2-29).

The ERCOT region has abundant biomass resources in the form of wood waste and other agricultural residues. Significant biomass sources include cotton gin trash, forestry, and biomass-derived waste from the large urban base. Prime agricultural areas include regions along the Gulf Coast, the central Blackland Prairie, and delta lands near the mouth of the Rio Grande. Switchgrass, a tall native grass proposed as an energy crop by the DOE, can be grown in all of these regions. Other locally abundant agricultural wastes include rice hulls, sugarcane, and cottonseed hulls. Manures generated throughout the ERCOT region also form an important resource (Reference 9.2-30).

Steam turbine conversion technology is relatively simple to operate and it can accept a wide variety of biomass fuels. However, at the scale appropriate for biomass (the largest biomass power plant listed by the EIA has a 74.9 MW nameplate capacity), the technology is expensive and inefficient, and is therefore relegated to applications where there is a readily available supply of low-cost, zero-cost, or negative-cost delivered feedstocks (Reference 9.2-25).

The domestic cost of biofuel (in 2006 dollars) varies from about $0.174/million British thermal units (MMBtu) for landfill gas, to $2.78/MMBtu for agricultural field residue, to $5.52/MMBtu for logging residue. The capital cost for a biomass power plant is between $1760 and $2160 per kilowatt (Reference 9.2-5). The levelized cost of electricity produced from biomass power plants in 2006 dollars is $0.063 to $0.118 per kilowatt-hour (Reference 9.2-19).

Biomass energy crops can produce a net fuel yield of 3.0 to 4.3 dry ton per acre per year (Reference 9.2-31), and the heat value is generally between 6450 and 8200 Btu/pound (Reference 9.2-32). For a nominal heat value of 7300 Btu/pound, and 40% conversion efficiency, the acreage required to grow enough biomass crop to generate 2700 MWe would be around 5.26 million acres, or 8200 square miles.

Although biomass offers some advantages, combustion of biomass fuels in modern power plants leads to many of the same kinds of emissions as the combustion of fossil fuels; including criteria air pollutants, greenhouse gases, and ash. Fuel processing, which in most cases involves some type of grinding operation, produces emissions of dust and particulates. Air emissions and water consumption are usually the principal sources of environmental concern related to biomass facilities (Reference 9.2-33).

Conversion of large tracts of land for production of energy crops would pose potentially adverse environmental impacts on wildlife habitat and biodiversity, reduce soil fertility, increase erosion, and reduce water quality. The net environmental impacts would depend on previous land use, the particular energy crop, and how the crop is managed. If the land has not previously been developed for farming or other purposes, displacement of natural land cover, such as forests and wetlands, with energy crops would likely have negative environmental impacts. In addition, conversion of food crops into energy crops means a reduction in food production that may need to be replaced elsewhere.

Based on this analysis, STPNOC has determined that biomass energy technology is developed, proven, and available in the ERCOT region at the start of commercial operation of the proposed project; however, biomass energy has large land use requirements and would produce substantial combustion gas emissions. Furthermore, the cost to generate electrical power from biomass systems is substantially greater than the costs of nuclear power. For these reasons, biomass power alone is not a feasible alternative for baseload power in the ERCOT region and is not environmentally preferable to STP 3 & 4.

9.2.2.3.6 Municipal Solid Waste

Municipal solid waste refers to the stream of garbage collected through community sanitation services. Since municipal solid waste generally includes some materials not suitable for combustion, segregation must be performed on the waste supply stream. For this reason, the capital and operations cost for a municipal solid waste generation plant are generally higher than other steam turbine generation plants that use a homogeneous waste feed such as wood waste (Reference 9.2-34).

The combustion of municipal solid waste can generate energy and reduce the volume of waste by up to 90% and the waste mass by up to 75%, an environmental benefit (Reference 9.2-35). However, municipal solid waste combustion also generates emissions of nitrogen dioxide, sulfur dioxide, and toxic pollutants such as mercury. The variation in the composition of municipal solid waste affects the emissions. For example, municipal solid waste that contains batteries and tires would generate higher levels of toxic emissions (Reference 9.2-34).

Power plants that burn municipal solid waste are normally smaller than fossil fuel power plants but typically require a similar amount of water per unit of electricity generated. When water is removed from a lake or river, fish and other aquatic life can be killed, which affects the animals and people who depend on these resources (Reference 9.2-34).

At the end of 2005, the EIA reported 96 municipal solid waste generation facilities in operation. Nameplate capacities range from 1.2 MWe to 90 MWe with combined output from all 96 plants of around 2650 MWe, and half of those are less than 20 MWe (Reference 9.2-26). It would require 30 municipal solid waste plants at 90 MWe to equal 2700 MWe of baseload capacity.

The overnight construction cost for a municipal solid waste generation facility (based on 2004 dollars) is about $1500 per kilowatt based on an 80 MW unit (Reference 9.2-36). The levelized cost for municipal solid waste-generated power (in 2000 dollars) is about $0.75 per kilowatt-hour (Reference 9.2-37).

The nominal heat content in municipal solid waste is around 11.7 MMBtu/ton, or about 5850 Btu/pound (Reference 9.2-38). There are about 20 million people that live within the ERCOT service area (Reference 9.2-39), and on average each person generates about 7.11 pounds of municipal solid waste per day which amounts to roughly 2600 pounds of municipal solid waste each year (Reference 9.2-40). This is more than the nation average of 4.5 pounds per day per person (Reference 9.2-41). About 35% of municipal solid waste generated is recovered for recycling (Reference 9.2-40). If the other 65% is burned to generate electricity and the combustion process is 30% efficient, the total annual energy potential in the ERCOT region from municipal solid waste would be around 2000 MW. This is less than the 2700 MW proposed by STPNOC.

Another option for conversion of landfill waste into electricity is to capture and burn the gases produced as municipal solid waste decomposes. This gas, which is primarily methane, can be collected from wells within the landfill, filtered, and used to fuel for engines connected to generators. Landfill gas generation plants are generally in the range of 3 to 8 MW, and can economically produce power for 10 to 15 years. In addition, combustion of the waste gas is beneficial to the environment because it prevents the introduction of raw methane, a greenhouse gas with global-warming potential 21 times that of carbon dioxide, into the atmosphere (Reference 9.2-42).

Based on this analysis, STPNOC has determined that municipal solid waste energy technology is developed, proven, and available in the ERCOT region at the start of commercial operation of the proposed project; however, because the full potential of municipal solid waste in the ERCOT region is still less than the 2700 MW needed, and because of the adverse environmental impacts to air and water quality, municipal solid waste is not environmentally preferable to STP 3 & 4.

9.2.2.3.7 Petroleum Liquids

Electricity generated in 2005 in Texas from combustion of petroleum liquids represented less than 0.5% of the total electricity generated in the state (Reference 9.2-20). Based on the ERCOT Unit Data Report for June 2007, petroleum-fueled (i.e., diesel) generation facilities in operation within the ERCOT region produce about 38 MW (Reference 9.2-21).

Although the capital cost for a new petroleum-fired plant would be similar to the cost of a new gas-fired plant, the viability of petroleum-fired electricity generation is linked to the price of crude oil, the rise of which has made petroleum-fired electricity generation relatively less economic. Based on a 2003 estimate, the levelized cost of electricity produced by conventional petroleum-fired operation is about $0.61 per kilowatt-hour (Reference 9.2-43). According to EIA, during the years 2003 through 2006, the average spot price of crude oil in the U.S. increased 120% from $26.60 per barrel to $58.41 per barrel (Reference 9.2-44). Future increases in petroleum prices are expected to make petroleum-fired generation even more expensive relative to other alternatives. Also, the United States depends heavily on foreign petroleum supplies (Reference 9.2-45). This reliance coupled with regional instability in the primary petroleum producing regions presents potential concerns with the long-term reliability and economic stability of petroleum-fired electricity generation. For these reasons, liquid petroleum is not considered an economically viable fuel source for new electricity generation facilities.

Construction and operation of a petroleum-fired plant would have identifiable environmental impacts. For example, NUREG-1437 estimates that construction of a 1000 MWe petroleum-fired plant would require about 120 acres. Based on a 95% capacity factor, a petroleum-fired power plant with a net output of 2700 MWe would require about 341 acres. Operation of petroleum-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant (Reference 9.2-2).

Based on this analysis, STPNOC has determined that petroleum energy technology is developed, proven, and available in the ERCOT region at the start of commercial operation of the proposed project, and that the land use requirements are relatively small; however, because of the high cost of the fuel, combined with concerns related to availability, energy independence, and the adverse environmental impacts to air and water quality, petroleum-fired generation is not a feasible alternative for baseload power in the ERCOT region.

9.2.2.4 Fuel Cells

Fuel cells are similar to common batteries. Both have a positive end and a negative end, rely on chemical reaction, and produce electricity when the circuit is closed. In hydrogen fuel cells, hydrogen passes through an anode catalyst where it is ionized. The hydrogen ions then pass through a conductive medium and combine with oxygen. The electrons formed by the ionization process create an electrical current. Fuel cells can generate up to 2 MW of power (Reference 9.2-5).

The fuel cell generation process is a clean technology because the byproduct is water. However, the hydrogen gas used in the fuel cells is generally obtained from fossil fuels—mainly natural gas. Fuel cells can be sized for grid-connected or customer-sited applications, but are generally too expensive to compete without subsidies (Reference 9.2-5).

Fuel cell power plants are in the initial stages of commercialization. Although more than 650 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel cell electricity generation capacity in 2003 was 125 MWe. The largest stationary fuel cell power plant ever built is 11 MWe (Reference 9.2-46). STPNOC believes that this technology has not matured sufficiently to support production for a baseload facility.

Fuel cells are not cost-effective when compared with other generation technologies, both renewable and fossil based. The estimated overnight construction cost (in 2006 dollars) is around $4015 per kilowatt (Reference 9.2-5), with a levelized electricity cost of $0.058 to $0.119 per kilowatt-hour based on a 2003 estimate (Reference 9.2-47).

Based on this analysis, fuel cell technology has not matured sufficiently to support production for a baseload facility, and is therefore not a reasonable alternative for baseload capacity due to the cost and production limitations.

9.2.2.5 Coal

The United States has abundant low-cost coal reserves, and the price of coal for electric generation is projected to remain steady for the next 20 years. By 2030, coal consumption is projected to increase by 50% over 2005 levels, with significant additions of new coal-fired generation capacity over the last decade of the projection period; however, projections for coal consumption are based on the assumption that current energy and environmental policies remain unchanged throughout the projection period (Reference 9.2-48). In year 2005, coal-fired generation facilities in Texas accounted for about 37.4 percent of the electricity generated and about 20 percent of its electric generation capacity (Reference 9.2-20).

There are three primary technologies identified to generate electrical energy from coal: conventional pulverized coal boiler, fluidized bed, and integrated gasification combined-cycle (IGCC). As part of the alternatives evaluation, all three technologies (conventional, fluidized bed, and IGCC) are evaluated.

9.2.2.5.1 Conventional Pulverized Coal Boiler

In conventional pulverized coal-fired plants, pulverized coal is blown into the combustion chamber of a boiler. The idea is that if the coal is sufficiently pulverized, it will burn almost as easily and efficiently as a gas. In the combustion chamber, hot gases and heat energy from the incineration process convert water into high-pressure steam. The steam is then passed through a turbine to produce electricity. Flue gases are routed through a selective catalytic reduction unit for nitrogen oxides (NO_x) reduction, and into an air heater. From the air heater the flue gas flows to a sulfur dioxide (SO_2) scrubber system and a particulate removal system.

The steam systems used in the current generation of pulverized coal plants are generally designated as subcritical (or conventional), supercritical, or ultra-supercritical. This designation is based on the pressure and temperature of the steam. The demarcation for these designations varies within the worldwide power generation industry (Reference 9.2-5).

In the United States, subcritical plants operate at a nominal pressure of 2400 psi and a peak temperature of 1050°F. A supercritical unit would operate at a similar peak temperature but at a nominal pressure of 3500 psi. Ultra-supercritical units operate at a nominal pressure of 4500 psi and a minimum temperature of 1100°F. As the temperature and pressure of the steam at the generator turbine inlet increases, so does the efficiency of the power steam cycle. As the efficiency of the steam cycle is increased, the amount of fuel necessary to produce the same amount of energy is reduced, which also reduces plant emissions (Reference 9.2-5). The subcritical and supercritical technologies are commercially mature and widely used throughout the world. The ultra-supercritical technology, however, is currently in the development phase and is not a feasible alternative for the proposed nuclear project. Pulverized coal-fired boilers provide an output between 100 and 1300 MWe (Reference 9.2-5). To mitigate the impact of a system failure on the electrical distribution system, most boiler/turbine combinations are generally less than 1000 MWe.

The environmental impacts of construction of a typical pulverized coal-fired steam plant are well known because coal-fired steam plants represent about a third of the electrical generation in the United States (Reference 9.2-20). The estimated capital costs (in 2006 dollars) for a new pulverized coal-fired power plant range from $1235 to $2270 per kilowatt (Reference 9.2-5). The levelized cost of new generation capacity from a pulverized coal-fired power plant is $0.056 per kilowatt-hour (Reference 9.2-48).

9.2.2.5.2 Fluidized Bed

Fluidized bed is an advanced coal combustion process that involves the injection of a sorbent material, such as crushed limestone, into the combustion chamber along with the fuel. The presence of the sorbent helps minimize the formation of gaseous pollutants. The fuel and sorbent mixture is fluidized on air jets in the combustion chamber to enhance combustion and heat transfer. Sulfur released from the fuel as SO_2 is captured by the sorbent to form a solid compound that is removed with the ash, generating large quantities of solid waste. The waste stream is potentially marketable for agricultural and construction applications. More than 90% of the sulfur in the fuel is captured in this process. NO_x formation in fluidized bed power plants is lower than that for conventional pulverized coal boilers because the operational temperature range is below the temperature at which thermal NO_x is formed (Reference 9.2-49). Overall, emissions from fluidized bed units are comparable to the emissions from a conventional pulverized coal boiler equipped with post-combustion SO_2 and NO_x control equipment. As discussed in Subsection 9.2.3.1, these environmental impacts are greater than those of a nuclear plant. Fluidized bed units are currently available in sizes as large as 300 MW, and designs are being developed for units as large as 600 MW. The technology is more suited to low-grade, high ash, high sulfur coals, which are more difficult to pulverize, and which may have variable combustion characteristics (Reference 9.2-50). Also, because the operational temperature of the fluidized bed system is lower, it does not achieve the higher efficiency levels achieved by conventional pulverized coal boilers.

To improve the thermal efficiency of the fluidized bed technology, a new type of fluidized bed boiler has been proposed that encases the entire boiler inside a large pressure vessel. Combustion of coal in a pressurized fluidized bed boiler results in a high-pressure stream of combustion gases that can spin a gas turbine to make electricity and boil water for a steam turbine. It is estimated that pressurized fluidized bed plants could generate 50% more electricity from coal than a regular power plant from the same amount of coal. The pressurized fluidized bed technology is currently in the demonstration phase and is not a feasible alternative for the proposed nuclear project. (Reference 9.2-49). Additionally, the fluid bed technology is not environmentally preferable to nuclear power.

9.2.2.5.3 Integrated Gasification Combined Cycle

IGCC is an innovative electric power generation concept that combines modern coal gasification technology with both gas turbine and steam turbine power generation. The technology is substantially cleaner than conventional pulverized coal plants because major pollutants can be removed from the inlet gas stream before combustion.

The IGCC alternative generates substantially less solid waste than a conventional coal-fired boiler. The largest solid waste stream produced by IGCC installations is slag, a black, glassy, sand-like material that is potentially a marketable byproduct. Slag production is a function of ash content in the coal (Reference 9.2-51). The other large-volume byproduct produced by IGCC plants is sulfur, which is extracted during the gasification process and can be marketed rather than placed in a landfill. IGCC units do not produce ash or scrubber wastes.

IGCC power plants are in the early stages of commercialization. There are currently two commercial-size, coal-based IGCC plants in the United States. Both were supported initially under the DOE Clean Coal Technology demonstration program, but now operate commercially without DOE support (Reference 9.2-51). Experience has been gained with the chemical processes of gasification, coal properties, and their impact on IGCC design, efficiency, economics, etc. However, system reliability is still relatively lower than conventional pulverized coal-fired power plants and the major reliability problem is from the gasification section. There are problems with the integration between gasification and power production as well. For example, if the gases are not adequately cleaned, uncleaned gas can cause various types of damage to the gas turbine (Reference 9.2-52).

An IGCC plant is estimated to cost about 20% to 25% more than a comparably sized conventional pulverized coal plant (Reference 9.2-51). STPNOC believes this technology has not matured sufficiently to support production for a large baseload facility and is not a reasonable alternative for a large baseload facility.

9.2.2.5.4 Conclusion for Coal-Fired Alternatives

Pulverized coal-boilers and fluidized bed units (if such units become commercially mature) are reasonable alternatives to the proposed nuclear plant. Because the supercritical pulverized coal technology has a higher thermal efficiency and lower emissions than either the subcritical pulverized coal or fluidized bed technologies, supercritical pulverized coal was selected as the representative technology for the coal-fired alternative. The coal-fired alternative includes four supercritical boiler units, each with a net capacity of 675 MWe for a combined capacity of 2700 MWe. Table 9.2-1 describes the assumed basic operational characteristics of the coal-fired units. Emission control technology and percent-control assumptions are based on alternatives identified by the EPA (Reference 9.2-53). For the purpose of analysis, it is assumed that coal and limestone (calcium carbonate) would be delivered by rail after upgrades are applied to the existing rail spur into STP.

Based on the well-known technology, fuel availability, and generally understood environmental impacts associated with construction and operation of a coal-fired power generation plant, it is considered a reasonable alternative and is therefore retained for further evaluation in Subsection 9.2.3.

9.2.2.6 Natural Gas

Gas-fired generation with combined-cycle turbines is mature and has relatively low capital costs. Overnight construction costs (based on 2006 dollars) for a combined-cycle turbine range from $565 to $620 per kilowatt (Reference 9.2-5). The levelized cost of electricity produced from a new gas-fired power plants in 2005 was around $0.055 per kilowatt-hour (Reference 9.2-48).

For the purpose of the gas-fired alternative analysis, four standard-sized units, each with an output of 675 MWe are postulated to achieve the target output of 2700 MWe. Table 9.2-2 describes assumed basic operational characteristics of the gas-fired units. It is also assumed that there would be sufficient gas availability.

Based on the well-known technology, fuel availability, and generally understood environmental impacts associated with construction and operation of a natural gas-fired power generation plant, natural gas is considered a reasonable alternative and is therefore retained for further evaluation in Subsection 9.2.3.

9.2.2.6.1 Combination of Alternatives

Although individual alternatives might not be sufficient to provide 2700 MWe capacity due to the small size of the resource or lack of cost-effective opportunities, it is conceivable that a mix of alternatives might be cost-effective and may also provide for a better environmental solution. There are many possible combinations of fuel types to generate 2700 MWe, and STPNOC has not exhaustively evaluated each combination. However, STPNOC reviewed combinations that, due to technological maturity, economics, and other factors, could be reasonable alternatives to the proposed project. Two of these combinations of alternatives are addressed below.

As discussed in Subsection 9.2.2.2, wind energy, as a stand-alone technology, is not a feasible alternative for baseload power. However, it is conceivable that a mix of wind energy and gas-fired combined cycle units could provide baseload power. For example, the 2700 MWe target capacity could be satisfied with a 600 MWe wind farm, along with 4 675 MWe natural gas combined-cycle units. During operation, a combined-cycle plant could ramp up and down quickly to “follow” the wind load. However, the impacts, including impacts to air quality, associated with the gas-fired plant alone would exceed those of the nuclear plant. Additionally, the wind portion of the alternative—land use impacts, noise impacts, and visual impacts—would be more than the stand-alone natural gas alternative; therefore, the combination would have greater adverse environmental impacts than a single fuel type. The cost of implementing the combination would also be greater than the cost of the stand-alone natural gas alternative. These conclusions would also apply for any combination of wind or solar coupled with any fossil fuel type facility. The environmental impacts and costs associated with the combined alternative would compare unfavorably with the proposed project.

If the hypothetical mix included coal-fired generation, the environmental impacts associated with construction (land use, ecology) and air quality would be expected to be greater than that of the proposed project. For example, the 2700 MWe target capacity could be met with two 675 MWe coal-fired units and two 675 MWe natural gas combined-cycle units. This combination coal-gas facility would require an estimated 291 acres for permanent structures. As discussed in Subsection 4.1.1, construction of the proposed project would disturb about 770 acres of which about 90 acres of these lost permanently due to construction of new facilities and a new heavy haul road. Air quality impacts for the 675 MWe coal-fired units would compare unfavorably with the proposed project due to the large quantity of combustion emissions from coal-fired generation. The additional impact, including combustion emissions, from the natural gas unit would only strengthen the overall favorable position of the proposed project.

Wind and solar facilities could be used in combination with storage systems to produce baseload power. By storing the power produced from wind or solar facilities and releasing it when the wind and solar facilities are not generating power, energy storage in combination with the wind or solar facilities would be able to generate electricity continuously. However, large-scale energy storage in Texas is either not available or would not be economically viable. For example, the storage of even one day's output at 2700 MW is well beyond any demonstration projects using batteries, compressed air, hydrogen, or other storage mechanism and the cost of such systems, even if available, would be prohibitive. Adding the significant cost of storage systems to the cost of wind or solar facilities would render the total cost non-competitive. In the northwestern United States, existing hydropower reservoirs are used to store and release the energy produced by wind generation. This combination of alternatives, in the form of "pumped storage," is not available in Texas at this scale. In addition to not being available, the costs to develop such storage would be prohibitive.

Other combinations of the various alternatives are not discussed here. In general, poor annual average capacity factors, higher environmental impacts (land use, ecological, air quality), immature technologies, and a lack of cost-competitiveness are not expected to lead to a viable, competitive combination of alternatives that would be either environmentally equivalent or preferable.

9.2.3 Assessment of Reasonable Alternative Energy Sources and Systems

This section evaluates the environmental impacts of reasonable alternatives to the proposed project: pulverized coal-fired generation and gas-fired generation. The significance of the impacts associated with each issue is identified as SMALL, MODERATE, or LARGE. This characterization is consistent with the criteria that NRC-established criteria in 10 CFR 51, Appendix B, Table B-1, Footnote 3, and presented as follows:

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purpose of radiological impacts assessment, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

Consideration is given to ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are SMALL receive less mitigative consideration than impacts that are LARGE).

9.2.3.1 Coal-Fired Generation

STPNOC has reviewed the NRC analysis of environmental impacts from coal-fired generation alternatives presented in NUREG-1437 and found the NRC analysis to be reasonable. Construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed; however, NRC pointed out that the installation of a new coal-fired plant where an existing nuclear plant is located would reduce many construction impacts. There are major adverse impacts from operations such as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

9.2.3.1.1 Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant would emit sulfur dioxide (SO_2, as SO_x surrogate), oxides of nitrogen (NO_x), particulate matter (PM), carbon monoxide (CO), and mercury (Hg), all of which are regulated pollutants. A coal-fired plant would also emit carbon dioxide (CO_2), which has been linked to global warming. As Subsection 9.2.2.10 indicates, it is assumed a plant design would minimize air emissions through a combination of boiler technology and post combustion pollutant removal. The coal-fired alternative emissions would be as follows:

SO_2 = 2900 tons per year

NO_x = 2000 tons per year

CO = 2800 tons per year

CO_2 = 27 million tons per year

Hg = 0.46 tons per year

PM_{10} (particulates with a diameter of less than 10 microns) = 50 tons per year

$PM_{2.5}$ (particulates with a diameter of less than 2.5 microns) = 13 tons per year

These emission totals are calculated based on the parameters and assumptions identified in Table 9.2-1 and emission factors published in AP-42 (9.2-53).

The acid rain requirements of the Clean Air Act Amendments establish a cap on the allowable SO_2 emissions from power plants. Each company with fossil fuel-fired units was allocated SO_2 allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_2 emissions. In 2005, emissions from generators in Texas ranked highest nationally for NO_x and fifth highest nationally for SO_2 (Reference 9.2-20). Both SO_2 and NO_x emissions would increase if a new coal-fired plant were operated at STP. To operate a fossil-fuel generation plant, STPNOC would have to purchase SO_2 allowances from the open market or shut down existing fossil-fired capacity from one of its owning members and apply the credits from that plant to the new one.

In March 2005, EPA issued the final Clean Air Interstate Rule which addresses power plant SO_2 and NO_x emissions that contribute to non-attainment of the 8-hour ozone and fine particulate matter standards in downwind states. Twenty-eight states, including Texas, are subject to the requirements of the rule. The rule calls for further reductions of NO_x and SO_2 emissions from power plants. These reductions can be accomplished by the installation of additional emission controls at existing coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

In March 2005, EPA finalized the Clean Air Mercury Rule which sets emissions limits on mercury to be met in two phases beginning in 2010 and 2018, and encourages a cap and trade approach to achieve the target emission limits. NO_x and SO_2 controls indirectly help to reduce mercury emissions. However, according to the EPA, the second phase cap reflects a level of mercury emissions reduction that exceeds the level that would be achieved solely as a co-benefit of controlling NO_x and SO_2 under the Clean Air Interstate Rule. Each new coal-fired electrical generation unit in Texas must acquire enough mercury allowances to cover its annual mercury emissions. Compliance with EPA mercury standards must be achieved by January 01, 2010 (Reference 9.2-54).

Texas has regions that are designated as non-attainment with respect to the National Ambient Air Quality Standards for one or more criteria pollutants. Therefore, the state of Texas was required to submit a State Implementation Plan to the EPA (1) to establish control strategies to reduce criteria pollutant emissions, and (2) to identify the technical and regulatory processes to demonstrate compliance with the State Implementation Plan. The Texas State Implementation Plan includes a cap and trade program for NO_x, SO_x, and Hg emissions. New stationary fossil fuel facilities in Texas must acquire trade credits to cover the new potential emissions. Compliance with the NO_x and SO_x standards identified in the State Implementation Plan must be achieved by January 01, 2009 and January 01, 2010, respectively (Reference 9.2-54).

The region of non-attainment nearest to the proposed project location is the Houston-Galveston-Brazoria region. Brazoria County is east of and conterminous with Matagorda County. This region is designated as moderate non-attainment with respect to the 8-hour ozone standard (40 CFR 81.344).

Air impacts from a coal-fired generation facility would be substantial. Adverse human health effects from coal combustion have led to important federal legislation in recent years because public health risks, such as cancer and emphysema, have been associated with coal combustion. Global warming and acid rain are also potential impacts. Recent changes in air quality regulations indicate that the EPA and the federal government recognize the importance of stability for air resources. SO_2 and mercury emission allowances, NO_x emission offsets, low NO_x burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatory-imposed mitigation measures. The coal-fired alternative would have MODERATE impacts on air quality—the impacts may be noticeable, but would not destabilize air quality in the area due to the use of mitigation technologies.

9.2.3.1.2 Waste Management

The coal-fired alternative would generate substantial solid waste. Based on the assumed plant parameters, the coal would have 3.9% ash content, and the facility would consume around 11 million tons of coal annually. Particulate control equipment would collect most (99.9%) of this ash (about 435,000 tons per year). If 75% of the coal ash were recycled, an annual total of about 109,000 tons of ash would require disposal.

SO_x-control equipment would require about 105,000 tons of limestone and would generate another 124,000 tons per year of waste in the form of scrubber sludge. Ash and scrubber waste disposal over a 40-year plant life would require about 141 acres.

With proper facility placement, coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within the current STP property for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. Waste disposal for the coal-fired alternative would have MODERATE impacts—the impacts of increased waste disposal would be clearly noticeable, but would not destabilize any important resource and further mitigation of the impact would be unwarranted.

9.2.3.1.3 Other Impacts

Construction of the power block and coal storage area would impact about 435 acres of land and associated terrestrial habitat. Because most of this construction would be in previously disturbed areas, impacts would be minimal. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion, sedimentation, and fugitive dust emissions could be anticipated, but would be minimized through application of best management practices. Onsite disposal is assumed for debris generated when the area is cleared and grubbed and that other construction debris would be accepted at a nearby municipal disposal facility.

Short-term socioeconomic impacts would result from the estimated 2414 construction workers to build the facilities, and long-term impacts would result from the estimated 315 full-time workers to operate the coal-fire facility. These impacts would be SMALL due to the influence of the nearby Houston-Galveston metropolitan area.

Cultural resource impacts would be unlikely due to the previously disturbed nature of the site and could be, if needed, minimized by survey and recovery techniques.

The existing STP Main Cooling Reservoir (MCR) would be used to minimize impacts to aquatic resources and regional water quality; therefore, STPNOC believes that these impacts would be SMALL.

The new stacks, boilers, and rail deliveries would be an incremental addition to the visual impact from existing STP structures and operations. Coal delivery would add noise and transportation impacts associated with unit-train traffic. Based on a unit train with 125 cars, where each car holds 100 tons, about 900 unit trains per year (about 17 trains per week) would be needed to deliver coal and limestone to the coal-fired plant.

Other construction and operation impacts would be SMALL. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these impacts, mitigation would not be warranted beyond that mentioned.

9.2.3.1.4 Design Alternatives

The in-land location of the STP site lends itself to coal delivery by truck. However, this design alternative would necessitate substantial upgrades to area roads. The alternative would trade truck traffic impacts for rail traffic impacts, a tradeoff that provides no obvious environmental benefit. Subsection 9.4.1 analyzes alternative designs for the STP 3 & 4 heat dissipation systems. Based on this analysis, STPNOC assumed the MCR would be used for the coal-fired alternative. Use of the existing MCR would minimize water consumption, thermal impacts, and additional visual intrusion; therefore, the heat dissipation system would pose a SMALL impact. The analysis of air quality impacts in Subsection 9.2.3.1.1 is based on use of best available control technology; therefore, there are no reasonable alternates for reducing those impacts.

9.2.3.1.5 Conclusion

As discussed in Subsection 9.2.2.10, STPNOC determined that coal-fired generation using supercritical boilers is a reasonable alternative to the proposed nuclear project because it is a mature technology, coal is available in the ERCOT region, and the environmental impacts associated with construction and operation of a coal-fired power generation plant are well understood. The impacts of coal-fired generation on the STP site are evaluated in Subsection 9.2.3.1 and STPNOC determined impacts would be SMALL to MODERATE. The impacts of coal-fired generation are compared to the proposed nuclear project in Tables 9.2-3 and 9.2-4. As these tables demonstrate, coal-fired plants are not environmentally preferable to nuclear power.

9.2.3.2 Natural Gas Generation

Subsection 9.2.2.11 presents the basis to select a combined-cycle plant as the gas-fired alternative. Land-use impacts from gas-fired units would be less than those of the coal-fired alternative. Reduced land requirements, due to construction on the existing site and a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources. As discussed under "Other Impacts," an incremental increase in the workforce could have socioeconomic impacts. Human health effects associated with air emissions would be of concern, but the effect would be less than those of coal-fired generation. The gas-fired alternative defined in Subsection 9.2.2.11 would be located on land adjacent to the STP site.

9.2.3.2.1 Air Quality

Natural gas combustion is relatively clean compared to other fossil fuel combustion. Also, because the heat recovery steam generator does not receive supplemental fuel, the combined-cycle operation is highly efficient (56% vs. 33% for the coal-fired alternative). Therefore, the gas-fired alternative would release similar types of emissions, but generally in quantities less than the coal-fired alternative. Control technology for gas-fired turbines focuses on the reduction of NO_x emissions. The gas-fired alternative would use about 121 billion standard cubic feet of natural gas per year and would generate these emissions:

SO_2 = 41 tons per year

NO_x = 680 tons per year

CO = 141 tons per year

CO_2 = 6.9 million tons per year

PM = 119 tons per year (all particulates are $PM_{2.5}$)

These emission totals are calculated based on the parameters and assumptions identified in Table 9.2-2 and emission factors published in AP-42 (9.2-53).

The Subsection 9.2.3.1 discussion of regional air quality, Clean Air Act requirements, the NO_x State Implementation Plan, and the Clean Air Interstate Rule also apply to the gas-fired generation alternative. SO_2 allowances, NO_x effects on ozone levels, and NO_x emission offsets could be issues of concern for gas-fired combustion. STPNOC concludes that emissions from a gas-fired alternative could noticeably alter local air quality and would not destabilize regional resources. Air quality impacts would therefore be MODERATE.

9.2.3.2.2 Waste Management

Gas-fired generation would result in almost no solid waste generation and would therefore produce minor (if any) impacts. STPNOC concludes that gas-fired generation waste management impacts would be SMALL.

9.2.3.2.3 Other Impacts

Similar to the coal-fired alternative, the ability to construct the gas-fired alternative on land adjacent to the STP site would reduce construction-related impacts relative to construction on a greenfield site.

A new 24-inch diameter pipeline would need to be constructed from an existing 24-inch transmission pipeline located about 2 miles northwest of the proposed site. Upgrades to the existing pipeline and gas storage facilities would also be required. To the extent practicable, new gas supply pipeline would be routed in previously disturbed areas to minimize impacts. Based on a 75-foot easement, about 18 acres would need to be graded to permit the installation of the pipeline. Construction impacts would be minimized through the application of best management practices to minimize soil loss and restore vegetation immediately after the excavation is backfilled. Installation of a gas pipeline would not create a long-term reduction in the local or regional diversity of plants and animals. In theory, impacts from construction of a pipeline could be reduced or eliminated if the gas-fired plant were located adjacent to an existing pipeline.

Construction of the combined-cycle plant would impact about 107 acres of land. Because this much previously disturbed acreage is available at the STP site, loss of terrestrial habitat would be minimal. Aesthetic impacts, erosion and sedimentation accumulation, fugitive dust, and construction debris impacts would be similar to the coal-fired alternative, but smaller because of the reduced site size. Socioeconomic impacts would result from the estimated 661 construction workers to build the facilities and 91 people needed to operate the gas-fired facility. These impacts would be SMALL due to the influence of the nearby metropolitan area.

9.2.3.2.4 Design Alternatives

Subsection 9.4.1 analyzes alternative designs for the STP 3 & 4 heat dissipation systems. Based on this analysis, STPNOC assumed the MCR would be used for the gas-fired alternative. Use of the MCR would minimize evaporative water loss, visual intrusion, and thermal impacts; the heat dissipation system would pose a SMALL impact. The analysis of air quality impacts in Subsection 9.2.3.2.1 is based on use of maximum achievable control technology; therefore there are no reasonable alternatives for reducing those impacts.

9.2.3.3 Conclusion

As discussed in Subsection 9.2.2.11, STPNOC determined that gas-fired generation using combined-cycle turbines is a reasonable alternative to the proposed nuclear project because it is a mature technology, natural gas is available in the ERCOT region, and the environmental impacts associated with construction and operation of a natural gas-fired power generating plant are well understood. The impacts of gas-fired generation on a site adjacent to the STP site are evaluated in Subsection 9.2.3.2 and STPNOC determined impacts would be SMALL to MODERATE. The impacts of gas-fired generation are compared to the proposed nuclear project in Tables 9.2-3 and 9.2-4. As these tables demonstrate, coal-fired plants are not environmentally preferable to nuclear power.

9.2.4 Conclusion

As shown in detail in Tables 9.2-3 and 9.2-4, based on environmental impacts, neither a coal-fired nor a gas-fired plant would provide an appreciable reduction in overall environmental impacts relative to a nuclear plant. Furthermore, each of these types of plants would entail a significantly greater relative environmental impact on air quality than would the proposed nuclear project. Therefore, neither a coal-fired or gas-fired plant would be environmentally preferable to the proposed project.

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Table 9.2-1 Coal-Fired Alternative

Characteristic	Basis
Unit size = 675 MWe ISO rating net [1]	Assumed
Unit size = 718 MWe ISO rating gross [1]	Calculated based on 6% onsite power
Number of units = 4	Assumed
Boiler type = PC, dry bottom, tangentially fired, sub-bituminous, NSPS	Minimizes nitrogen oxides emissions (Reference 9.2-49)
Fuel type = Powder River Basin Sub-bituminous coal	Typical for coal used by NRG Energy
Fuel heat value = 8200 Btu/lb	NRG Energy Experience (Reference 9.2-55)
Fuel ash content by weight = 3.9%	NRG Energy Experience ((Reference 9.2-55)
Fuel sulfur content by weight = 0.3%	NRG Energy experience (Reference 9.2-55)
Uncontrolled NO_x emission = 7.2 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (Reference 9.2-53)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (Reference 9.2-53)
Heat rate = 8,568 Btu/kWh	Assumed based on DOE data (Reference 9.2-56)
Capacity factor = 0.85	Typical for large coal-fired units
NO_x control = low NO_X burners, overfire air and selective catalytic reduction (95% reduction)	Best available and widely demonstrated to minimize NO_x emissions (Reference 9.2-53)
Particulate control = fabric filters (baghouse-99.9% removal efficiency)	Best available for minimizing particulate emissions (Reference 9.2-53)
SO_x control = Wet scrubber - limestone (95% removal efficiency)	Best available for minimizing SO_x emissions (Reference 9.2-53)

[1] The difference between “net” and “gross” is electricity consumed onsite.

Btu = British thermal unit

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds per square inch of atmospheric pressure

kWh = kilowatt hour

NSPS = New Source Performance Standard

MWe = megawatt electrical output

NO_x = nitrogen oxides

SO_x = oxides of sulfur

Table 9.2-2 Gas-Fired Alternative

Characteristic	Basis
Unit size = 675 MWe ISO rating net [1]	Assumed
Unit size = 703 MWe ISO rating gross [1]	Calculated based on 4% onsite power
Number of units = 4	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,029 Btu/ft^3	2005 value for gas used in Texas (Reference 9.2-20, Table 6)
Fuel SO_x content = 0.0007%	Reference 9.2-57
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available to minimize NO_x emissions (Reference 9.2-58)
Fuel NO_x content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (Reference 9.2-58)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units (Reference 9.2-58)
Fuel $PM_{2.5}$ content [2] = 0.0019 lb/MMBtu	Reference 9.2-58, Table 3.1-2a
Heat rate = 5,960 Btu/kWh	Assumed based on Siemens SCC6-5000F 2x1 plant configuration (Reference 9.2-59)
Capacity factor = 0.85	Assumed based on performance of modern plants

[1] The difference between “net” and “gross” is electricity consumed onsite.

[2] All particulate matter is $PM_{2.5}$.

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60% relative humidity, and 14.696 pounds of atmospheric pressure per square inch

MM = million

$PM_{2.5}$ = particulates with a diameter of 2.5 microns or less

Table 9.2-3 Impacts Comparison Summary

Impact Category	Proposed Action (STP COL)	Coal-Fired Generation	Gas-Fired Generation	Combinations of Alternatives
Land Use	SMALL	SMALL	SMALL	SMALL to LARGE
Water Quality	SMALL	SMALL	SMALL	SMALL
Air Quality	SMALL	MODERATE	MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	SMALL	SMALL to LARGE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL to LARGE
Human Health	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL	SMALL to LARGE
Waste Management	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL	SMALL to LARGE
Cultural Resources	SMALL	SMALL	SMALL	SMALL
Accidents	SMALL	SMALL	SMALL	SMALL

Table 9.2-4 Impacts Comparison Detail

Proposed Action (STP COL)	Coal-Fired Generation	Gas-Fired Generation	Combination of Alternatives
Alternative Descriptions			
New construction at the STP site	New construction at the STP site.	New construction on land adjacent to the STP site.	New construction at the STP site, a greenfield site, or a combination of the two. Site selection would be dependent on the technologies selected.
Two 1350-MWe (net) ABWR reactors	Four 675-MWe (net) tangentially-fired, dry bottom boilers.	Four 675-MWe (net) combined-cycle units that includes two 198-MWe gas turbines and a 279-MWe heat recovery steam generator.	A combination of two or more of the technologies described in Subsection 9.2.2.
	Pulverized bituminous coal, 8,200 Btu/pound; 8,568 Btu/kWh; 3.9% ash; 0.3% sulfur; 7.2 lb/ton NO_x; 11 million tons of coal per year.	Natural gas, 1,029 Btu/ft^3; 5,960 Btu/kWh; 0.00066 lb SO_x/MMBtu; 0.0109 lb NO_x/MMBtu; 121 billion cubic feet of gas per year.	
	Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency).	Selective catalytic reduction with steam/water injection.	
	Wet scrubber –limestone desulfurization system (95% SO_2 removal efficiency); 105 thousand tons of limestone per year. Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency).		
	Upgrade existing rail spur.	Disturb about 18 acres to construct 2.0 miles of gas pipeline with a 75-foot-wide corridor. May require upgrades to existing pipelines.	The need for material transport facilities would depend on the technologies selected.
New closed cycle cooling water system that utilizes the MCR	New closed cycle cooling water system that utilizes the MCR.	New closed cycle cooling water system that utilizes the MCR.	The need for a cooling water system would depend on the technologies selected.
5950 peak construction workers.	4467 peak construction workers.	1637 peak construction workers.	The number of construction workers would depend on the technologies selected.
Land Use Impacts			
SMALL – 90 acres required for facility at the STP site (this acreage excludes the MCR).	SMALL – 435 acres at the STP site required for the powerblock and coal storage; 141 acres ash/scrubber waste disposal (this acreage excludes the MCR).	SMALL – 107 acres for facility at the STP site; 18 acres for gas pipeline (this acreage excludes the MCR).	SMALL to LARGE – The amount land required would depend on the technologies selected, but could range from 100 acres to more than 600 square miles.

Table 9.2-4 Impacts Comparison Detail (Continued)

Proposed Action (STP COL)	Coal-Fired Generation	Gas-Fired Generation	Combination of Alternatives
SMALL – Construction impacts would be minimized by use of best management practices. Operational impacts would be minimized by use of the MCR and compliance with applicable TCEQ water quality standards.	SMALL – Construction impacts would be minimized by use of best management practices. Operational impacts would be minimized by use of the MCR and compliance with applicable TCEQ water quality standards.	SMALL – Construction impacts would be minimized by use of best management practices. Operational impacts would be minimized by use of the MCR and compliance with applicable TCEQ water quality standards.	SMALL – Construction impacts would be minimized by use of best management practices. Operational impacts, if any, would be dependent on the technologies selected and the location of the generating facilities. Operational impacts would be minimized by use of best management practices and compliance with applicable TCEQ water quality standards.
Air Quality Impacts			
SMALL – Construction impacts would be minimized by use of best management practices. Operational impacts are negligible.	MODERATE – 2,900 tons SO_2 per year 2,000 tons NO_x per year 2,800 tons CO per year 27 million tons CO_2 per year 0.46 tons Hg per year 50 tons PM_{10} per year 13 tons $PM_{2.5}$ per year	MODERATE – 41 tons SO_2 per year 680 tons NO_x per year 141 tons CO per year 6.90 million tons CO_2 per year 119 tons $PM_{2.5}$ per year [1].	SMALL to MODERATE – Construction impacts would be minimized by use of best management practices. Operational impacts are dependent on the combination of technologies selected. Emissions could be zero or they could be as much as the emissions from the coal-fired alternative.
Ecological Resource Impacts			
SMALL – Construction of the power block would permanently impact about 90 acres of terrestrial habitat and would displace various species. Use of the MCR would minimize impingement, entrainment, and thermal impacts to aquatic species.	SMALL – Construction of the power block and coal storage areas and 40 years of ash/sludge disposal would permanently impact about 576 acres of terrestrial habitat, displacing various species. Use of the MCR would minimize impingement, entrainment, and thermal impacts to aquatic species.	SMALL – Construction of the power block and pipeline would impact up to 125 acres of terrestrial habitat, displacing various species. Approximately 107 acres would be permanently impacted. Use of the MCR would minimize impingement, entrainment, and thermal impacts to aquatic species.	SMALL to LARGE – Depending on the technologies selected, construction could impact 100 acres to more than 600 square miles of terrestrial habitat. Impacts to aquatic resources would be dependent on the site and the technologies selected. Use of cooling towers and best management practices for the intake and outfall, if needed, would minimize impingement, entrainment, and thermal impacts to aquatic species.

Table 9.2-4 Impacts Comparison Detail (Continued)

Proposed Action (STP COL)	Coal-Fired Generation	Gas-Fired Generation	Combination of Alternatives
Threatened or Endangered Species Impacts			
SMALL – No areas designated as critical habitat exist at or near the STP site. Transmission lines would have no adverse impacts on protected species because no new transmission lines rights-of-way or new transmission lines would be required.	SMALL – No areas designated as critical habitat exist at or near the STP site. Transmission lines would have no adverse impacts on protected species because no new transmission lines rights-of-way or new transmission lines would be required.	SMALL – No areas designated as critical habitat exist at or near the STP site. Transmission lines would have no adverse impacts on protected species because no new transmission lines rights-of-way or new transmission lines would be required.	SMALL to LARGE – Impacts would depend on the site and the technologies selected, and 100 acres to more than 600 square miles of terrestrial habitat could be impacted, and any endangered, threatened, and other special status species that occur in the project area could be disturbed. STPNOC and ERCOT procedures would be employed to minimize adverse impacts to protected species and their habitats.
Human Health Impacts			
SMALL – Impacts associated with noise are not anticipated. Radiological exposure is not considered significant because doses would be within federal limits. Risk from microbiological organisms is minimal due to thermal characteristics at the discharge. Risk due to transmission-line induced currents is minimal due to conformance with consensus code.	MODERATE – Risks such as cancer and emphysema from emissions are likely.	SMALL – Some risk of cancer and emphysema exists from emissions.	SMALL to MODERATE – Depending on the combination of technologies selected, risks such as cancer and emphysema from emissions could be likely.
Socioeconomic Impacts			
SMALL – Increase in permanent workforce at STP by 888 workers could affect adjacent counties.	SMALL – Increase in permanent workforce at STP by 315 workers could affect surrounding counties.	SMALL – Increase in permanent workforce at STP by 91 workers could affect surrounding counties.	SMALL–Given the infinite number of combinations of alternatives that could be pursued, it is impossible to determine the size of the permanent workforce. It is likely however, that the workforce would be less than or equal to the permanent workforce under the coal fired alternative.

Table 9.2-4 Impacts Comparison Detail (Continued)

Proposed Action (STP COL)	Coal-Fired Generation	Gas-Fired Generation	Combination of Alternatives
Waste Management Impacts			
SMALL – Non-radiological impacts would be negligible. Radiological impacts would be SMALL. All radioactive wastes would be managed according to established laws, regulations, and exposure limits.	MODERATE – 109,000 tons of coal ash and 124,000 tons of scrubber sludge would require 141 acres over the 40-year term.	SMALL – Almost no waste generation.	SMALL to MODERATE – Waste generation would be dependent on the combination of technologies selected. Many of the possible technologies have no waste streams while others, like coal-fired boilers, have substantial waste streams.
Aesthetic Impacts			
SMALL – Visual impacts would be consistent with the industrial nature of the site.	SMALL – Visual impacts would be consistent with the industrial nature of the site.	SMALL – Visual impacts would be consistent with the industrial nature of the site.	SMALL to LARGE – Visual impacts would be dependent on the combination of technologies selected and the location of the site where the facilities would be located.
Cultural Resource Impacts			
SMALL – Impacts to cultural resources would be unlikely due to disturbed nature of the site. STPNOC maintains procedures to protect cultural resources.	SMALL – Impacts to cultural resources would be unlikely due to disturbed nature of the site.	SMALL – Impacts to cultural resources would be unlikely due to disturbed nature of the site.	SMALL – Site selection would be dependent on the technologies selected. A formal cultural resources survey would be conducted so that no archeological or historic resources would be damaged during construction. Mitigative measures would be performed to prevent permanent damage and ensure that any impacts to cultural resources from construction or operation would be SMALL.
Accident Impacts			
SMALL – Although the consequences of accidents could be potentially high, the overall risk of accidents is low given the low probability of an accident involving a significant release of activity.	SMALL – Impacts of accidents in coal-fired plants are limited.	SMALL – Impacts of accidents in gas-fired plants are limited.	SMALL – Impacts of accidents from any combination of the technologies described in Subsection 9.2.2 would be limited.

[1] All particulates for gas-fired alternative are PM2.5.

Notes: SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource. (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3).
Btu = British thermal unit
DHEC = Department of Health and Environmental Control
ft^3 = cubic foot
gal = gallon
kWh = kilowatt-hour
lb = pound
MM = million
MW = megawatt
NO_x = nitrogen oxides
PM_{10} = particulates with a diameter less than 10 microns
$PM_{2.5}$ = particulates with a diameter less than 2.5 microns
SO_2 = sulfur dioxide